POLICY OPTIONS FOR REDUCING GREENHOUSE GAS EMISSIONS FROM POWER IMPORTS

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Background

This draft paper is the first of five issue papers prepared by the Center for Clean Air Policy in support of the Energy Commission's *2005 Integrated Energy Policy Report.* Specifically, this paper is intended to examine the potential design of policy options to reduce greenhouse gas (GHG) emissions from both in-state and out-of-state power sources, including the possible design of a cap-and-trade system for California.

This paper also supports one of the primary recommendations resulting from the West Coast Governors' Global Warming Initiative that the States of California, Washington and Oregon work together to examine the need to develop a regional market-based carbon allowance program.[1]

This paper addresses the strong interest in the specifics of alternative policy designs among California state agencies and interested stakeholders, including the members of the Energy Commission's Climate Change Advisory Committee. The paper evaluates alternative cap-and-trade policy designs for both imported power and in-state power resources and examines three alternatives in the California context: 1) multi-state approaches; 2) emission portfolio standards; and 3) caps on emissions associated with power demand. Lastly, the paper describes how the third option, the cap on emissions associated with power demand, might be designed.

Introduction

In the United States, a cap-and-trade policy design has been used to reduce SO_2 and NO_x emissions from the electric power sector with considerable success. In the case of SO_2, emissions from the largest electric power generators were capped in 1995, with more generators participating starting in 2000. In the case of NO_x emissions, eastern states that were part of the ozone transport region, and later the State Implementation Plan (SIP) call region, capped emissions from electric generation (and large industrial boilers) in their states and allowed trading among participating sources across the respective trading regions.

Other cap-and-trade programs have been implemented in Illinois and in Europe addressing VOC and CO_2 emissions, respectively, from various stationary sources. All of these programs had one thing in common: they capped emissions from individual sources. Such programs generally required installation of continuous emission monitors (CEMs), or, in the case of volatile organic compound (VOC) trading, establishment of standard methodologies for estimating emissions from a given source. Tracking of emissions and emissions

[1] West Coast Governors' Global Warming Initiative: Staff Recommendations, November 2004.

reductions under these programs has been fairly straightforward, making it easy to match actual emissions with allowances and ensure compliance.

While generation-based cap-and-trade programs have proven to be very successful when implemented at the national level in the U.S. or over broad regions such as the eastern United States, there are several reasons why this might not be the best approach for California:

- First, very significant levels of imported power are used to meet California demand, including a large amount of imported coal, a source of carbon dioxide emissions. These emissions associated with imported power would be missed under a generation-based cap.

- Second, programs that cover smaller regional areas and where neighboring states are exempt have a high risk for leakage[2]. This leakage could erode the emissions benefits of a generation-based trading program.

- Third, there is a more limited (and more costly) set of potential mitigation activities from electric generating sources in California. Alternative policy designs can broaden the opportunity for lower-cost mitigation actions by expanding the total generation that is affected by the cap.

These issues are further explored below.

Addressing emissions from imports

Unlike many other states, power demand in California is met with a high level of imported power. California has depended on imports for one-fifth of its power in recent years, and nearly half of the carbon dioxide emissions associated with in-state demand come from imported coal-fired power. There are currently no coal-fired plants located within California.

While the standard way of capping emissions involves limiting emissions from in-state generation, in California's case, this approach would miss a significant and growing fraction of the emissions released to meet in-state power demand. To address the full footprint of California's climate impact, GHG emissions from both in-state and out-of-state resources used to meet California power demand should be controlled.

[2] The term leakage refers to the transfer of power demand and associated emissions to uncapped sources in neighboring states. This concept is discussed in more detail below.

Reducing the potential for leakage

Leakage can occur where the establishment of an emissions control regulation creates disparities in cost between regulated and unregulated sources or regions. To the extent that the marginal control costs increase in areas that are regulated, sources in unregulated areas experience a cost advantage. Under a competitive power market, this cost disparity can result in increases in generation and emissions by uncapped plants that are able to sell power into the regulated region, with simultaneous decreases in generation and emissions from sources subject to an emissions cap.

In this way, leakage can reduce or even eliminate the emissions reductions expected to be achieved by the cap-and-trade program. The effect can be especially large if the unregulated plants with a cost advantage also have higher average emissions rates. The potential for leakage under regional cap-and-trade programs has been shown in recent power sector modeling exercises conducted for the Connecticut Climate Change Stakeholder Dialogue and more recently, for the Regional Greenhouse Gas Initiative.

In Connecticut, power sector modeling conducted with the Integrated Planning Model (IPM) considered the effects of a generation-based cap and trade program covering ten states (Maine, Vermont, New Hampshire, Rhode Island, Massachusetts, Connecticut, New York, New Jersey, Pennsylvania, Delaware), with the cap set at 1990 levels in 2010, 5 percent below 1990 levels in 2015, and 10 percent below 1990 levels in 2020. While the policy was predicted to result in large reductions in CO_2 emissions, the total reductions achieved were significantly reduced by leakage.

By making power in the 10-state region more expensive relative to power purchased from outside the region, the program resulted in increased power imports. For example, in 2010, net power imports to the 10-state region were projected to increase by over 300 percent under the cap. Since this power is predominantly from coal-fired sources, the increase in emissions associated with imported power offsets a portion of the reductions achieved.

Overall, leakage was projected to reduce the aggregate emission reductions for the 10-state region from over 30 million metric tons of carbon dioxide equivalent ($MMTCO_2e$) to nearly 15 $MMTCO_2e$ in 2010 (over 50 percent), and from nearly 70 $MMTCO_2e$ to less than 20 $MMTCO_2e$ in 2020 (over 70 percent).

Similarly, the preliminary IPM modeling results presented to the Regional Greenhouse Gas Initiative (RGGI) stakeholder group suggests the presence of leakage.[3] ICF Consulting modeled the application of various power sector caps

[3] The Regional Greenhouse Gas Initiative was established in April 2003 by the Northeastern and Mid-Atlantic States to design a regional cap-and-trade program limiting carbon dioxide emissions from power plants.

applied to the northeast states from Maine to New Jersey (but not including Pennsylvania and Maryland). Preliminary results found that, while in the reference case, power imports decline from about 90 terawatt-hours (TWh) in 2006 to less than 35 TWh in 2024, this decline in imports is reduced under the different cap scenarios.

For example, under a cap set at 15 percent below 1990 levels, imports go from about 90 TWh in 2006 to about 60 TWh in 2024. Imports in 2024, therefore, are projected to be more than 25 TWhs higher under the cap scenario than under the reference case. These additional imports are mostly comprised of new natural gas-fired generation, with very small amounts of existing and new coal generation, existing gas generation, and other resources. The higher imports under the cap scenarios would be expected to reduce the overall CO_2 reduction benefits resulting from the RGGI cap. This effect is mitigated when lower demand levels are assumed.

A number of structural characteristics of the California power system suggest that leakage will be an important concern. Specifically:

- California power generation has an emissions rate of 633 pounds of carbon dioxide per megawatt-hour (lb CO2/MWh) while non-California power generation in the WECC region averages 1,188 lb/MWh.[4] This difference suggests that any increase in imported power from the reference case would likely erode a portion of the emissions benefits from a California generation-based cap.

- The cost of power in California averaged 13.4 cents per kilowatt-hour (kWh) in 2002, while the average cost of power in the non-California WECC region is estimated at 6.5 cents per kWh in 2003. Further expansion of this price gap resulting from an in-state cap on power generation would continue to favor power imports.

- The high prices paid for power sold into California have already resulted in a significant level of power imports and emissions. Over the last few years, power imports from plants outside the state accounted for roughly one-fifth of the state's electricity demand. Emissions from out-of-state power plants are estimated at 54 $MMTCO_2$ in 1999, nearly equal to the in-state emissions (57 $MMTCO_2$) from the power sector within California.

- New coal-based generation appears to be economic in the West. The Energy Information Administration projects almost 35 GW of new coal builds in the WECC from 2005-2025 in its Annual Energy Outlook 2005 base case run. That's over 40% of total new coal capacity predicted for the entire US.

[4] These averages were estimated from the US EPA's Emissions & Generation Resource Integrated Database (eGRID) 2002. The data are for year 2000.

For these reasons, a generation-based cap applied only to California units may result in little overall emissions benefit, and could potentially cause an increase in GHG emissions due to leakage.

Encouraging lower-cost mitigation options

Setting aside the potential for leakage in applying a generation-based cap to California, there are also significant limits to the effectiveness of a CA-based cap that is applied to the current generation mix. Specifically, California CO_2 emissions largely come from natural gas-fired power generation. In fact, natural gas units account for about one-half of total in-state generation, with zero-emission nuclear, hydro and renewable sources accounting for nearly all of the remainder.

Options for reducing GHG emissions at natural gas fired plants relate primarily to increasing capacity factors at the most efficient units and reducing (or eliminating) capacity factors at the least efficient units. There is also the potential to boost generation efficiency at existing plants, re-power combustion turbines to combined cycles, re-power existing units to IGCC with carbon capture and sequestration, or undertake combined heat and power and/or biomass co-firing.

Because natural gas-fired units are already relatively low-emitting, these measures will be more expensive on a cost per ton basis to apply to gas generation than to coal-based generation, increasing overall program costs per ton of emissions reduced compared to a similar program applied to a region with more coal-fired power generation and further enhancing the potential for leakage at tighter cap levels.

Reductions from natural gas-fired units may still be cost-effective when compared against reductions from other sectors in California. The point here is that by expanding the control region by extending the program to indirectly reach generation serving California power demand, it may be possible to make reductions from this sector even more cost-effective.

Description of Policy Alternatives to Generator-Based Cap-and-Trade

This paper looks at three alternative policy designs in the California context: 1) multi-state approaches; 2) emission portfolio standards; and 3) caps on emissions associated with power demand. It then goes on to describe how the third option, the cap on emissions associated with power demand, might be designed.

Multi-state approaches

One way to capture imported power emissions is to expand the cap to cover those states that are expected to experience growth in power demand and emissions under a California-based cap-and-trade program. Those states with sizeable coal investments, however, may be unwilling to take action to limit the growth in GHG emissions. Other states may be interested in establishing a trading system, but the process of designing a system that is fair and equitable to all parties can be time consuming.

Until neighboring states supplying coal-fired power generation to California (e.g., Arizona and New Mexico) are ready to engage in the design of a regional cap-and-trade program, it makes sense for California to focus on policy designs to address emissions from imported power that can be implemented independently. Leadership by California in establishing a cap-and-trade program may streamline the process for neighboring states to opt-in and could make it easier for these states to take this step.

Emission portfolio standard

An emission portfolio standard would require all load-serving entities (LSEs) and/or generators selling power to the state to meet an output rate in lb/MWh or other standard of environmental performance. Each LSE would be responsible for ensuring that the power it purchases, whether from in-state or out-of-state resources, meets this established rate on average. In addition, power generators selling directly to end users would need to meet the same emissions rate. (Note that it is possible that additional compliance avenues are possible as any given rate can be translated into an absolute emissions level. If this were allowed, it would be possible for an LSE to buy carbon allowances to meet an EPS.)

The Northeast States for Coordinated Air Use Management (NESCAUM) has established a model rule for use by New England states seeking to level the environmental playing field and improve environmental quality. This model rule, if implemented, would limit out-of-state as well as in-state emissions of NO_X, SO_2, CO_2, mercury and potentially CO to proposed standards. These standards are periodically reviewed and revised.

The proposed design uses an output based standard which applies to retail suppliers rather than electric generating facilities. The standard applies to each power product sold by retail suppliers to avoid disadvantaging renewable energy products, and to prevent renewable energy consumers from paying for more than their fair share of the compliance burden. Trading and banking are not allowed between products or across retail suppliers.

Compliance is determined on an annual basis, but retail suppliers must report quarterly. Compliance is determined by calculating the weighted average emissions of the product portfolio, expressed in pounds per MWh, and comparing the result to the standards. In instances where emissions are not tracked or it is difficult to ascertain where the power was produced, the NESCAUM model rule suggests using state or regional default values based on regional averages to the south and west.

Electricity suppliers that do not meet the standard are required to offset the excess emissions in the following year. Interestingly, the NESCAUM model rule does not appear to include financial penalties. Normally, financial penalties are used to provide an incentive to comply.

Several states have laws authorizing the establishment of emissions portfolio standards for various pollutants as part of electricity restructuring legislation. The details of these programs and their implementation to date are as follows:

- The Massachusetts restructuring legislation gives the Massachusetts Department of Environmental Protection authority to regulate any pollutant with a generation portfolio standard. This legislation further directs Massachusetts to implement a standard for at least one pollutant by May 1, 2003. To date, the state has not done so.
- Connecticut restructuring legislation directs the Connecticut Department of Environmental Protection to establish generation performance standards for five pollutants: SO_2, NO_x, CO_2, CO and Hg. Implementation of these standards is contingent upon neighboring states adopting similar standards. A Connecticut draft rule includes a generation performance standard of 1,100 lb CO_2/MWh. This standard is consistent with the one proposed in the NESCAUM model rule.[5]
- The New Jersey Board of Public Utilities can issue an EPS for SO_2, NO_x and CO_2 upon finding that such standards are needed to meet ambient air quality standards. However, prior to implementation, at least two other states within the Pennsylvania-New Jersey-Maryland (PJM) power control area would need to adopt emission portfolio standards.

Key advantages of an emission portfolio standard include the establishment of a signal to load-serving entities, and indirectly, to power generators both inside and

[5] The purpose of the NESCAUM model rule is to ensure that "the generation of power to serve the region's retail customers is characterized by an equal or improved level of environmental performance relative to what would otherwise be required of generation resources in the Northeast. Hence, the standards levels were derived from emissions levels that will be required or are already being achieved by generators in the region." (p.19-20) The CO_2 rate was based on meeting 1996 emissions levels (current levels at the time of the analysis) using 1996 generation rates. Specifically, NESCAUM rounded down from a rate of 1,138 lb/MWh to 1,100 lb/MWh. New England emissions levels in 1996 were nearly 12% below 1990 levels. Sustaining this rate, authors believed, would also help achieve the Kyoto target.

outside these states, that lower-emitting generation has value. Currently, the dominant considerations that drive the choice of generation are price and transmission.

An emissions portfolio standard (EPS) will result in sales of existing low-emitting generating resources to the state(s) that adopt EPS requirements, and potentially encourage the development of new, lower-emitting generation sources. Depending on where the standards are set and the number of states that adopt standards, an EPS could potentially limit the amount of coal-fired generation that can be sold to states with standards, requiring coal-fired generators to seek out other markets, or lower production.

While an EPS sends signals indicating a preference for lower emitting power, there are several important limitations of this policy, including the potential for contract shuffling, the potential for emissions increases as demand grows, and difficulties in tracking emissions for purposes of compliance. In addition, the design would need to be executed carefully to avoid conflicts with the Interstate Commerce Clause.

Contract shuffling could occur under an EPS if existing low emitting power were sold to the state with the EPS, and higher-emitting power was sold outside the regulated state. Under this scenario, compliance would be demonstrated on paper, and there would be fewer emissions associated with the regulated state's power, but overall emissions reductions would not be achieved. While these kinds of power shifts are likely to occur as a result of an EPS, we would want to prevent gaming that involves deliberate attempts to double count resources or take advantage of potential loopholes in the tracking system. These issues are discussed further in the section describing a cap on emissions associated with power demand.

The NESCAUM model rule suggests ways to diminish gaming by expanding the size of the market affected by EPS requirements and by designing comprehensive information systems, including comparable reporting systems in all states serving in-state demand. If comparable systems do not exist, NESCAUM proposes assigning default emissions characteristics to imported power.

Expanding the size of the market affected by the EPS may be possible in California. While, as noted in the previous section, it will be politically difficult to encourage neighboring coal states to adopt climate regulation, whether a cap or an EPS, it may be possible to encourage lower-emitting neighboring states such as Oregon and Washington to adopt an EPS. This approach would increase the market for low-emitting power versus higher-emitting coal-fired generation, enhancing the regional incentive within the west for new lower-emitting power and for reduced generation from higher-emitting sources.

Importantly, in addition to the possibility that gaming will reduce program effectiveness, an EPS will not necessarily reduce emissions or even maintain emissions at a particular level. By establishing an emissions rate rather than an overall cap, an EPS would allow emissions to increase to the extent that power demand increases.

If power demand increases over time, as expected, the emissions associated with power demand would be allowed to increase provided that the emissions rate limit is met. Current California demand projections, including the expected reductions in demand associated with the CPUC/CEC energy efficiency goals, average roughly 1 percent per year growth between 2005 and 2025. Under an EPS that does not shift over time, emissions would be allowed to grow at that same rate.

Under an EPS, there would be challenges in tracking emissions and monitoring compliance. Electrons from a given power generator cannot be tracked to the consumer. Rather, electrons are sold into the grid at large and move based on the physics of the transmission and distribution system. Through long-term contractual arrangements or via the spot market, power from a given generator may be sold to one or more load serving entities.

Power is often resold by brokers. Not only is tracking such power transfers difficult, the emissions attributes of the power are not currently reported or tracked. A solution to these tracking challenges is needed for an EPS to be a viable regulatory solution. This solution will require a system that tags emissions for every megawatt-hour of power generated. The LSE would be required to hold and disclose these emission tags to demonstrate compliance. (See the tracking discussion below under the cap on emissions associated with power demand for more details, as many of the issues are the same.)

Finally, an emissions portfolio standard needs to be designed in a way that avoids conflict with the Interstate Commerce Clause (ICC). The ICC ensures that any requirements that a state imposes on out-of-state sources applies equally to in-state sources (i.e., it is not allowable to apply different rates to imported power and in-state power).

Placing the requirement on the LSE helps to mitigate these problems as all power generation sources would be subject to the same indirect incentives to sell clean power into the State. Placing requirements on generators that sell to the LSE or to an end user would require that the standard be set at the same level for all plants. For some states, setting a standard at a level that would have the desired effect on out-of-state generation would also disadvantage certain in-state resources. This is unlikely to be the case for California, where in-state emission rates are all significantly below the prevailing out-of-state power averages.

Cap on emissions associated with power demand

A cap on emissions associated with power demand in California would cap total CO_2 (or CO_2e) emissions from sales of electricity to California. All load-serving entities would be required to hold emission allowances for the total power they sell into the regulated state, regardless of where the original generating source supplying power to the state is located.

This option would create an incentive for the LSE to purchase low-emitting power in lieu of higher-emitting power to meet their overall cap. The load-serving entity would have several ways to comply with this cap requirement, including purchase of emission allowances from other LSEs, replacement of higher-emitting fossil generation purchases with lower or zero-emitting generation resources, and investments in energy efficiency. While in the short term there would be greater reliance on purchase of existing low-emitting resources, in the longer term, depending on the cap level, this program could create an incentive for new low-emitting resources. This program may also encourage longer-term contracting with cleaner resources.

Incentives to invest in demand-side energy efficiency and renewable energy may be stronger under a cap on emissions associated with power demand than in the case of a cap on generation. This is because a cap on generation applies to different types of generators that have varying types of expertise. Some merchant generators, for example, are not in the business of energy efficiency, demand side management or renewable energy, and would be less likely to use these avenues for compliance. LSEs, in contrast, generally have greater familiarity with and access to a variety of clean generating resources.

A cap on emissions associated with power demand has not been implemented anywhere. This policy mechanism was considered within RGGI at the suggestion of the Regulatory Assistance Project, but the modeling has proceeded using a cap on generation.

Implemented in California, a cap on emissions associated with power demand would essentially create two separate power markets within the western grid – the capped California demand market, and the uncapped remainder of the grid.

The California demand market would have a preference for low-emitting power resources to meet the cap. Both in-state and out-of-state generation resources would be treated on a level playing field on the basis of the market they choose to serve. Cleaner generation resources located in California and in neighboring states will gain a cost advantage vis-à-vis their higher-emitting competitors. While a cap on emissions associated with power demand is expected to advantage California power generators, the effects on consumers will depend on several factors, including the level of the cap and the chosen allocation method. A cap set at levels to prevent growth in coal-based power generation may have a negligible impact on electricity prices, whereas a cap set to achieve significant reductions from the sector would be expected to result in higher electricity costs with increased purchases of clean sources of power. The expected impacts on electricity prices of different cap levels will be better understood after the planned power sector modeling work is completed. Another factor is the chosen allowance allocation method. An output-based allocation with updating, for example, has been shown in some cases to lead to lower electricity prices than other forms of allocation.[6] This can occur as a result of shifts in the marginal price-setting power units. As output from cleaner generating sources is encouraged by an output updating allocation, these units run more. To the degree that these units are lower in cost and increasingly on the margin, the overall cost of the cap program will come down.

Importantly, to the degree that there is an electricity price increase from a cap on emissions associated with power demand, a current proposal by the CPUC suggests that the cap program can be designed to be revenue neutral. Essentially, any increase in electricity costs would be balanced by reductions in existing line charges used to support energy efficiency and renewable energy.

The cap on emissions associated with power demand would be expected to limit the degree to which leakage can occur. While under a generation-based cap, it is possible for the expected leakage to exceed the total emissions reductions expected by the cap-and-trade program, this would not be possible under a cap on emissions associated with power demand. In the worst case, there would be no leakage in the form of more sales of coal-fired generation into California but there could be a zero overall net effect of the program at higher costs for California in the instance that generation in the system remains the same but load-serving entities shift sales or contracts of existing generation to meet the California cap.

In addition to addressing the leakage issue resulting from displacement of in-state power with higher-emitting out-of-state power, a key advantage of a cap on emissions associated with power demand is that, unlike an EPS, emissions are subject to an absolute limit, irrespective of growth in generation. In addition, as mentioned earlier, a cap on emissions associated with power demand may also do a better job of encouraging adoption of end-use efficiency and renewable energy than a traditional generation-based cap-and-trade program.

Disadvantages of a cap on emissions associated with power demand include: 1) the potential for compliance through reallocation of existing resources or contracts (e.g., contract shuffling) instead of development of new low-emission power resources to serve California electricity demand; 2) challenges in tracking

[6] See, for example, Palmer, Karen, “Allocating Emission Allowances: General Overview and Insights from Analysis of a Carbon Policy,” Resources for the Future, presented to the Center for Clean Air Policy’s Air Quality Dialogue on Multi-Pollutant Approaches, November 26, 2002.

emissions and monitoring compliance; and 3) increased potential for problems with power reliability.

There is a high likelihood that LSEs will choose to shuffle contracts as a means of compliance, particularly in the short- and medium-terms while waiting for additional clean generation to be built. Essentially, LSEs serving the California market will choose to buy existing clean generation over higher-emitting coal-fired power. The higher-emitting resources would likely be picked up by LSEs that service other western demand markets.

To the extent there is sufficient out-of-state power demand and sufficient low-emitting resources to service the California market, contract shuffling allows high-emitting sources from in-state and/or out-of-state to avoid the California cap, and may give a premium price to low-emitting resources sold in California. Interestingly, given the relatively high amounts of zero-emitting power generation in the west, it is possible that a very tight cap in California could be met with existing resources entirely through contract shuffling. For example, as it now stands, if all of the zero emitting power in the west could be sold and transmitted to California, the state would currently be able to meet a cap set at a very low level (in tons of CO_2). While many kinds of power shifts result from a legitimate form of compliance, the State would want to prevent contract shuffling that involves deliberate attempts to double count resources or take advantage of potential loopholes in the tracking system.

For example, the State would want to prevent renewable generation from selling to Colorado to meet a Colorado renewable portfolio standard and to California to meet a cap on emissions associated with power demand. The state may also want to prevent plants from selling power to California that would be technically impossible to deliver to market because aggregate power sales exceed the maximum available transmission capacity.

A second major challenge is in tracking emissions and monitoring compliance. The actual electrons from a given power generating unit cannot be tracked all the way to the consumer. Rather, electrons are sold into the grid at large and move based on the physics of the transmission and distribution system. Power from a given unit, plant or company may be sold to one or more load serving entities through long-term contractual arrangements or via the spot market. Power is often resold by brokers.

Not only is tracking such power transfers difficult, the emissions attributes of the power are not currently reported or tracked. A solution to these tracking challenges is needed for a cap on emissions associated with power demand to be a viable regulatory solution. Some ideas are discussed in the next section.

A third concern with respect to implementing a cap on emissions associated with power demand is the increased potential for problems with power reliability. One potential problem could arise from significant increases in transmission across specific lines. For example, a given line currently supplying power to California at a level below its maximum carrying capacity might increase to levels near the maximum capacity, potentially leading to transmission disruptions. A second potential problem could involve the dependency of the grid upon particular plants for voltage support. If the California cap were to lead one of these key plants to shut down, this loss of power could create reliability problems or transmission bottlenecks.

There is an additional risk that a cap on emissions associated with power demand will encourage shifts in buying habits by LSEs serving the California market, with little or no increase in the construction of new generating capacity. Some LSEs buy and sell power but are not in the business of building new generating resources. This program relies on the market forces of supply and demand to create an incentive for new clean generating unites. If this new generation is not built, there could be reliability concerns related to insufficient amounts of clean generation to meet the California market demand.

To ensure against reliability concerns, which have been a problem for California in the recent past due to illegal gaming by sellers on price, the State may want to consider program designs to mitigate the potential for reliability problems.

One solution might involve coupling a cap on emissions associated with power demand with new incentives for clean generating technology to serve the California market and, if needed, to provide voltage support. Other solutions relate to providing enhanced compliance flexibility. These solutions will be discussed in the next section.

Design of a cap on emissions associated with demand

A number of issues will need to be considered in designing a cap on emissions associated with demand for California. Planned modeling of a cap on emissions associated with power demand scenario with the NEMS model may shed light on various design alternatives. Further discussions with California stakeholders and other experts may uncover additional wrinkles and potential solutions. The observations that follow are, therefore, preliminary.

Setting the cap level

Considerations in setting a cap level may include cost factors, emissions reductions, and the public perception. Key cost factors include the estimated marginal cost per ton of emissions reduced, total system costs, and energy costs associated with different cap scenarios. These cost factors will be influenced by the ability to develop low- or no-GHG generation and the effects of existing and new state policies and programs such as renewable energy requirements and energy efficiency incentives. Other key assumptions affecting the cost of a cap on emissions associated with power demand include expected growth in electricity demand, the characteristics of existing generation capacity, existing transmission constraints, and renewable portfolio standards in other western states.

The cap-and-trade program might be set to maximize mitigation, such that all of these cost values stay within a reasonable range. Alternatively, the cap could be set at a level that would encourage all new generation built to meet California demand to be low- or zero-emitting. This later approach acknowledges the difficulty of reducing emissions from existing natural gas generation in California and from the large and relatively efficient coal-fired power generation that dominates in the western United States. The biggest opportunity is likely to be to offset projected emissions increases associated with new fossil-fired generation. Another possible rule in setting the cap would be to establish the cap at a level that is expected to result in no increase in coal-fired power imports and potentially a reduction.

An updated version of the NEMS model currently being developed can be used as a tool for understanding the cost and emissions implications of setting different cap levels. This modeling will also show the degree to which different types of compliance mechanisms (e.g., shifts in generation by fuel type, efficiency improvements, and construction of new clean generation) are used to achieve these caps, if at all.

Tracking emissions and monitoring compliance

Implementation of a cap on emissions associated with power demand will require development of a new system or refinement of an existing system to track and verify power generation and sales. The tracking system needs to be accurate, transparent, consistent, and widely accepted, and must address the diversity of contractual situations.

Several systems have been developed for tracking environmental aspects of kWh, including the New England Generation Information System (NE-GIS) and the Western Renewable Energy Generation Information System (WREGIS). The NE-GIS tracks the emission attributes (CO_2 and criteria pollutants) of all electricity sold in the New England region, while the WREGIS will be an independent certificates-based system to track and verify renewable energy generation in the Western electricity grid.

In both cases, the primary initial use is for compliance with state-based renewable portfolio standards. In addition, both systems allow for trading of certificates. If allowed by a state program, certificate trading means that the renewable energy can be developed anywhere in or outside of the system as long as the power is sold into the respective grid.

For a tracking system to be adequate to support a CO_2 (or CO_2e) cap on emissions associated with power demand, several modifications would be needed. In the case of WREGIS, the program would need to:

1. Include all units selling power into the Western grid, not just renewable energy;

2. Include reporting of unit-level CO_2 emissions and the quantity of emissions associated with power sold to different LSEs serving the California market;

3. Require the LSE to obtain and report the original emissions certificates associated with their purchased power; and

4. Develop a methodology to allocate unit-level emissions to LSEs. Normally, LSEs purchase power from a plant or company, not an individual unit. However, emissions are monitored on a unit basis. Options for allocating unit-level emissions to LSEs include unit-specific approaches that seek to account for actual unit sales to a given LSE, or use of plant or company averages.

In addition to the above parameters, the tracking system for the cap would need to be used to ensure that renewable energy sold in Colorado to meet a Colorado renewable portfolio standard is not also sold into California to meet the cap on load. The WREGIS system is already set up to tag renewable energy resources so preventing double counting should not be a problem.

Another key issue is whether to build on the existing WREGIS or to start fresh with a new tracking system developed to support the cap on emissions associated with power demand. In the case of WREGIS, which is being developed primarily to support renewable energy trading, there will be resistance to splitting out specific emissions attributes, as this could dilute the value of the renewable credit and add complexity. Also, there appears to be a mismatch between the rules for selling renewable energy and the rules that would be needed for a successful CO_2 (or CO_2e) emissions market.

Specifically, renewable energy credits in WREGIS can be sold separately from power, while emissions credits are best sold with power to achieve the emissions reduction goal. Sold separately, it may be impossible to prevent significant amounts of existing zero-emitting generation from far-flung parts of the WECC from being used to meet the CO_2 cap.

While the location of CO_2 reductions isn't a problem from a climate change standpoint, it may reduce the likelihood that emission reductions from the cap are additional to what would have happened anyway and promote a shell-game approach to compliance. Expected resistance by specific interests in WREGIS to the kinds of changes that would make a cap on emissions associated with power demand a successful program suggests advantages to a fresh start.

Another set of tracking issues involves finding solutions that address the diversity of contractual situations, including direct sales to end users, sales through brokers, sales to LSEs from a company, plant or unit, and spot market sales.

Spot market sales may be the hardest contractual arrangement to track given that sellers change from one minute to the next. In addition, it will be important to prevent high-emitting power from selling into the spot market undetected. Three possible designs for preventing undetected coal sales to the spot market are: 1) establishing separate spot markets for high-, medium- and zero-emitting sales, 2) assuming that all spot market sales are high-emitting coal-fired power generation, or 3) exempting a limited amount of spot market sales from the cap.

Separate spot markets has the advantage of encouraging all types of power to sell on the spot market without being significantly advantaged or disadvantaged vis-à-vis alternative contractual arrangements. On the other hand, tracking of emissions would be required and it may be necessary to develop a new California spot market that has the tiered emissions characteristics. LSEs serving California would then be required to buy from this new spot market.

Assuming that all spot market sales are high-emitting coal-fired power generation would give an added incentive for load-serving entities to use longer-term contracts for renewable energy or other low-emitting resources, potentially facilitating lower cost financing and further deployment, while reducing the need to track emissions from companies selling on the spot market. However, this assumption would also create a disincentive to use the spot market and lead to more long-term contracts and loss of some of the expected benefits of market-pricing of electricity.

Exempting a limited amount of spot market sales from the cap has the advantages of minimizing any rate impacts that would result from capping emissions from the spot market and eliminating the need to track spot market sales up to the prescribed limit. This approach also has the effect of focusing the cap where it will do the most good – on longer-term investments that have the potential to change the composition of the electric resource portfolio over time. A main disadvantage of exempting a limited amount of spot market sales from the cap is that coal-fired generation will have a greater incentive to sell on the spot market to be exempted from the cap yet still sell to the California market. This would need to be considered in setting the overall level of a cap. In addition, if the actual spot market size exceeds the exempted amount, another solution to treating the remaining spot market purchases will be needed.

Gaming/leakage problems

Separate from the tracking solutions discussed earlier, there are various ways to limit the degree to which contracts can be shuffled. For example, an analysis could be done on transmission line availability to ensure that additional power cannot be sold over transmission lines that are nearly full. Similarly, safeguards could be added to ensure that power generators cannot sell the same power twice. The latter issue may be addressed through the existing certificates program discussed earlier and expanded to additional generation.

Preventing sales to California that exceed the potential for transmission into the state would likely require a study of the power that is contracted for sale to California versus the power that could actually be transported across specific transmission lines. To be most effective, such a study would need to focus on peak periods when transmission constraints are most likely to take place. To support such an analysis, reporting of generation and the associated emissions would need to be done on an hourly or peak period basis. There are alternative rules that can be used to allocate transmission resources during peak periods, including:

- First come, first served – generators that have historically used a given transmission line continue to get first dibs on access. This may favor large coal plants in the Southwest over their competitors.

- Highest bidder – generators willing to pay for the transmission get access to it. It may not be possible to get access to individual bid data. If it could be implemented, this approach favors companies with the highest margins. These are likely coal plants unless the cap is very tight.

- Lowest marginal cost of power – favors certain zero-emitting resources (wind, hydro, nuclear) over higher-cost power.

- Proximity/line loss – plants with the least line loss get first access, reducing the likelihood for wheeling power from far-flung locations such as Montana or Mexico.

- Pro rata shares – plants that purport to sell to California would get a prorata fraction of the available transmission.

- Cause of reliability problems -- The plant(s) determined to cause the transmission constraint, generally due to proximity to the line (for existing plants) or establishment of a new plant that did not mitigate the potential effects on transmission, would not get access to transmission. While this rule most closely matches how the California ISO grants access to transmission, this information is not available to the public.

> Therefore, there would be added barriers to implementation. If it could be implemented, this rule would protect the status quo.

While the California ISO tracks which plants use transmission resources on an hourly basis, this information is not available to the public.

One way to avoid gaming problems, as proposed by the Regulatory Assistance Project to participants in the northeast Regional Greenhouse Gas Initiative, would be to assume that all power imports meet a system average emission rate. RAP further proposes an exception could be made for new power resources that have direct contracts with California LSEs. This approach would eliminate the gaming issue altogether as there would be no incentive to sell existing lower-emitting power to California as the assumed emissions rates for all imports would be the same. New renewable energy generation and other low-emitting generation could still be encouraged as a compliance option due to the exception carved out for this purpose. However, there could be problems as out-of-state power is now treated differently from in-state power. Namely, existing out-of-state low-emitting generation (nuclear, gas and renewable energy) would not have the same preferential treatment as in-state low-emitting resources and therefore would not see the added demand and price benefits. This differential treatment could pose a problem under the commerce clause and is therefore not recommended.

Reliability

To address the reliability concerns discussed earlier, state regulatory agencies should consider adopting a companion program to encourage penetration of new, low-emitting generation (potentially including carbon capture and sequestration), provide voltage support and/or address transmission constraints that impact the ability of low-emitting resources to get to market. This program could involve expanding upon or replacing existing capacity markets to require resource adequacy in a way that also provides incentives for new low-emitting resources to meet California power demand, particularly in areas that with higher-emitting plants that provide voltage support for the grid[7].

Additional investments in new transmission capacity in areas expected to require expansion of transmission would help prevent potential reliability disruptions. Coupling a cap with capacity market incentives results in a push/pull dynamic where incentives for new, clean capacity help meet the objectives of the CO_2 control requirements in a way that also helps to address reliability concerns. Both sets of requirements can be tailored to load-serving entities, ensuring that the push/pull dynamic affect the same entity.

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[7] It may be necessary to coordinate with WECC transmission managers to identify and track program impacts on plants that are important for voltage support.

As next steps, it will be necessary to evaluate existing systems for providing for sufficient capacity to meet power demand, such as the Los Angeles resource procurement approach, and to identify the kinds of changes needed to create a preference for clean power generation.

Additional considerations to ensure reliability is maintained under a cap on emissions associated with power demand relate to providing compliance flexibility. Use of emissions trading, offset systems and emissions banking may be needed to program liquidity. In addition, use of long lead times and long (e.g., 5-year) compliance averaging periods should be considered as a way to allow for the construction of new, cleaner generation to help meet compliance and to reduce the likelihood of compliance difficulties resulting from unexpected short-term demand increases, contractual problems or other factors. In addition, California should consider the use of price caps to prevent compliance costs that are deemed to be too high. These measures need to be further explored and defined.

Allowance allocation

In general, the same methods for allocating allowances to generators are available to allocate allowances to LSEs. Design options include: 1) grandfathering based on the carbon content of fuel input (expressed in lb/MMBtu) in a given year or average of years; 2) grandfathering based on emissions per unit of electrical output (lb/MWh) in a given year or average of years; 3) periodic updating based on carbon content of fuel input; 4) periodic updating based on emissions per unit of electrical output; 5) modifications of these approaches (e.g., an output approach that would recognize and reward energy efficiency measures); or 6) an allowance auction.

The choice of allocation method affects the degree to which data from generators must be gathered and tracked. In all cases, emissions data are needed from the generator. But in the case of input-based allocations, information on types and quantities of fuels would also need to be tracked. For this reason, we suggest limiting the discussion to output-based and auction allocation methods. An output-based approach may encourage purchases from more efficient generation, while an auction would produce revenues that could be recycled for other uses, such as funding energy efficiency programs, as proposed by the CPUC.

Key distinctions between an updating and grandfathering approach are the degree to which existing LSEs are favored vis-à-vis new ones. Grandfathering advantages existing LSEs, particularly ones that serve a constant or declining load over time, while updating is preferable to new LSEs that begin after the start of the trading program and those that expand their markets. Economists have critiqued updating as providing an incentive to sell more power to win additional allowances. Infrequent updating may be a reasonable solution that does not provide an incentive to generation while at the same time ensuring that new LSEs are not significantly disadvantaged.

In addition, under an output-based allocation, allowances may be allocated either based on purchases from emitting units only, or from all generating sources (including nuclear, hydro and renewable sources). The first case advantages LSEs that buy more fossil resources, while the second gives allowances for zero-emitting resources, encouraging such purchases. Purchasers of fossil resources will need the allowances to comply, whereas those that buy more renewable resources would be receiving an asset they could sell.

The total allocation of permits to each LSE (or under an auction, the total allowances to be sold) would be based on actual emissions associated with California power demand. Under the non-auction scenarios, these emissions would need to be further apportioned to LSEs. This exercise is not straightforward; there are potentially several alternative approaches for estimating emissions associated with California demand as many plants have more than one unit.

In cases where a given plant has only one generating unit or where the particular unit transmitting the power is specified, this will not be an issue. In other cases, where multiple generators are located at a given plant, there will be two basic allocation options. A simple approach would be to apply the plant-wide average output emission rate to a given quantity of power purchased by an LSE. This approach could employ either a single rate or several rates estimated over a few different time periods (e.g., monthly, ozone season) to correspond with fuel consumption patterns and power purchases. The advantage of this option is that it is relatively easy to administer.

A more complicated approach would develop a methodology to link the specific day and/or hour of purchase to the generating profile of a given plant. This methodology would thus account for the level of base load versus peak power purchased by each LSE. In the case of a plant that generates using both coal and gas units, for example, the gas units are more likely to be online primarily during peak hours, and an LSE that purchased from this plant during base load periods may thus be allocated a higher quantity of emissions (from mostly coal-fired power) for each kWh than an LSE that purchased more peak power. This approach adds precision, but potentially significant complexity in having to track power on an hourly basis rather than on an annual basis.

A related issue concerns the portion of an LSE's portfolio that has been purchased on the spot market or from other LSEs. Since the ultimate source of such power cannot be readily determined in many cases, it will be necessary to assign a default emission rate to these purchases for purposes of determining the allocation.

Options would include applying an average regional emissions rate, or one based on a specific fuel. If a grandfathering allocation approach is used, the specific emissions rate assigned to each kWh of purchased spot market power will have no impact on LSE behavior (since allocation will be based on a past year).

With an updating approach, however, setting the emissions rate at a relatively low level (e.g., allocating few allowances to spot market purchases) may lower the incentive to purchase power on the spot market for sale under the cap (while setting the emissions rate at a relatively high level would increase the incentive to purchase power on the spot market). Since this power is more difficult to track and to assign an accurate emissions value, we suggest setting the default emissions rate for purposes of allocation at a low level for spot market purchases.

Linking

Another consideration in the design of a cap on emissions from power demand is the degree to which it can link to other state or national trading programs. As it does not matter from a climate standpoint where the GHG reductions take place, and there are potentially cost savings associated with expanding the scope of trading and compliance options, it is desirable to design California's trading system so that it can be linked up with others that meet an equal degree of rigor.

Linking a cap on emissions associated with power demand with other programs such as the Regional Greenhouse Gas Initiative may involve jumping through a few more hoops than would be required with a generation-based cap-and-trade program. On the one hand, a ton of CO_2 is a ton of CO_2, and the same kinds of issues would be evaluated to assess program equivalency as would be considered in the event of a program capping generation. The key task will be building confidence in the overall program stringency, monitoring and enforcement.

Additional issues arise when considering use of different cap approaches in California vis-à-vis neighboring states such as Oregon and Washington. If California were to use a cap on emissions associated with power demand and a neighboring state were to use a cap on generation, there would likely be double counting issues where both states may be counting the same generation resources, in one case, because the generation is serving California demand, and in the other case, because the generation is located in that state. There would be an added incentive for plants counted by both states to make reductions. As these reductions would be counted twice, the total effectiveness of the trading programs in terms of emissions reductions would be reduced. (The reductions from the two programs would not be additive.) To avoid the need to reconcile inconsistent programs, it would make sense for neighboring states to follow California's lead in the choice of program design.

Legal issues

A cap on emissions associated with power demand must serve a legitimate state interest and be designed in a way that provides equal treatment for in-state and out-of-state sources. Previously, protection of the health and safety of citizens and the integrity of natural resources has been determined to be a legitimate state interest under Maine v. Taylor, 106 S.Ct. 2440, 2454 (1986). According to an assessment by the Regulatory Assistance Project, "reducing CO2 emissions will provide both and it is reasonably necessary to include imported power within the cap in order to achieve these reductions." Non-discrimination is met under a cap on load. In fact, a generation-based cap would arguably discriminate against California power resources. However, care needs to be taken in the design of the policy to ensure that in-state and out-of-state resources have equal treatment.

Accordingly, as noted earlier, using an assumption that out-of-state power meets a system average while in-state power can be unit specific would treat low-emitting plants from out-of-state differently from their in-state counterparts, and would probably be illegal.

A second issue that could raise conflicts with the commerce clause relates to how renewable energy sources are counted. Some argue that California's limits on qualifying renewable energy to meet the renewable portfolio standard creates a bias in the event that a cap on emissions associated with power demand is also established. Specifically, under this scenario, a renewable resource in California could be used to meet both the California renewable portfolio standard and a cap on emissions associated with power demand. However, a renewable resource located out-of-state in most cases could only be used to meet either a renewable portfolio standard outside of California or a California cap on emissions associated with power demand.

Others contend that the problem stems from the renewable portfolio standard requirement and not with the cap on emissions associated with power demand. Therefore, a cap should not raise issues with the commerce clause.

More analysis is needed to understand the applicability of the commerce clause to this renewable energy issue. For example, we will need to consider whether disallowing renewable energy sources to be double counted qualifies as a legitimate state interest.

Another legal question relates to whether state jurisdiction is preempted by FERC under the Federal Power Act (FPA). The FPA grants FERC jurisdictional authority over electric power transmission and wholesale power transactions. It is important that a cap on load be designed so as not to infringe those powers. In applying a cap to LSEs, as is done under renewable portfolio standards, the state would impose a restriction on final retail power sales, not wholesale sales or transmission. In this way, the state stays within its own jurisdictional authorities and does not infringe FERC jurisdiction.

Conclusions

In the California context, we believe a cap on emissions associated with power demand has some clear advantages over a cap on generation, including the ability to address emissions from out-of-state plants, the ability to more directly encourage development of energy efficiency and renewable energy, and reduced potential for leakage. The success of a cap on emissions associated with power demand rests on resolving data and monitoring and verification issues.

Ultimately, before designing a cap program of any kind, it will be important to understand the potential for emissions reductions by those plants serving California demand and the degree to which a cap on emissions associated with power demand is likely to encourage these actions. It will also be helpful to look at the degree to which a cap on emissions associated with power demand will affect the choice of new power generation. If it turns out that the best that can be accomplished is reducing emissions from new power generation serving California demand, state policymakers will need to consider whether an emissions cap is the best way to achieve this, particularly given the complexity of a cap applied to emissions from demand.

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